Distribution Integrity Management Frequently Asked Questions

Revision Date: August 2, 2010

A. Excess Flow Valve Requirements

The Integrity Management Program for Gas Distribution Pipelines Final Rule included a revision to 49 CFR Part 192.383 Excess Flow Valve Installation which mandated the installation of excess flow valves (EFV) in certain new and replaced residential service lines.

A.1 Must an operator install an EFV in branch (split) service lines serving single-family residences?

No. Operators are required to install EFVs in new or replaced service lines serving single-family residences. A service line serving a single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence.

Operators are not required, but may choose to install EFVs in other applications as part of their risk mitigation strategy.

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A.2 Must operators retrofit excess flow valves into existing service lines?

Operators are only required to install EFVs where single family residential service lines are newly installed or are replaced for other reasons. The rule defines "replaced" as where the fitting that connects the service line to the main is replaced or the piping that is connected to this fitting is replaced. Replacement of other portions of a service line (e.g., near the meter) would not trigger the requirement to install an EFV.

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A.3 Will excess flow valves provide protection for gas line breaks on customer piping inside a residence?

EFVs required by this regulation are not designed or intended to protect against breaks or leaks on customer piping inside a home. EFVs are intended to cut off the supply of gas to the downstream service line in the event of major damage (e.g., a line severed by excavation damage).

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A.4 Where must the EFV be installed on a service line?

An operator is required to locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply. Examples of acceptable locations include installing an EFV that is built into the service tee, installing a short section of pipe between the service tee and the EFV to allow for the pipeline to be squeezed off upstream of the EFV, and installing an EFV out from under pavement to facilitate future access. Operators may use reasonable judgment in determining the most appropriate location for an EFV.

Last Revision: 8/2/10

A.5 Will an operator have to notify other customer classifications of the availability of excess flow valves?

No. The notification requirement was repealed.

Last Revision: 8/2/10

A.6 Since installation of EFVs is mandated for all new and replaced service lines serving single-family residences where EFVs are feasible, why do operators still need to report them?

PHMSA is required by the *Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES)* to collect this data.

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A.7 Does the operator report the number of EFVs installed per year or the total number of EFVs installed on an operator's system on the Annual Report form? Does the number include EFVs installed on services other than single-family residences?

Operators are to report the total number of EFVs installed in the system on service lines serving single-family residences. The "Number of EFVs in System at End of the Year on Single-Family Residential Services" is reported on the Annual Report form in Part E – Excess Flow Valve (EFV) Data. Operators may, but are not required, include EFVs installed on branched services serving single-family residences in the total. PHMSA is currently revising the Annual Report form for the 2010 calendar year to accommodate this information.

(Note: The due date for reporting EFVs is currently under review).

Last Revision: 8/2/10

A.8 The regulation exempts the installation of EFVs on services which do not operate at a pressure of 10 psig or greater throughout the year. Can you give examples of types of documentation that would be acceptable in demonstrating this issue?

Two possible methods to demonstrate that services operate at a pressure less than 10 PSIG include; (1) distribution system design documents, validated with actual pressure readings, which show that the main and therefore the associated services are designed to operate below 10 PSIG, or (2) actual pressure recordings or readings on all feeds which are upstream of the service(s) which are less than 10 psig.

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B. General Distribution Integrity Management Program Questions

B.1 DIMP Fundamentals

B.1.1 Why did PHMSA mandate integrity management requirements for distribution pipeline systems?

PHMSA's regulations in part 192 have contributed to producing an admirable safety record. Nevertheless, incidents continue to occur, some of which involve significant consequences, including death and injury. It is not possible to significantly reduce high consequence pipeline incidents without reducing the likelihood of their occurrence on distribution pipelines. PHMSA used an integrity management approach similar to that used for transmission pipelines, with appropriate modification to reflect the different nature of distribution pipelines, to accomplish this safety improvement. These incidents often involve unique circumstances or characteristics of a particular pipeline system/ segment or its operation.

The *Pipeline Integrity, Protection, Enforcement, and Safety Act of 2006* (PIPES) mandated that PHMSA prescribe minimum standards for integrity management programs for distribution pipelines. The law provided for PHMSA to require operators of distribution pipelines to continually identify and assess risks on their distribution lines, to remediate conditions that present a potential threat to pipeline integrity, and to monitor program effectiveness. Instead of imposing additional prescriptive requirements for integrity management, PHMSA concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective given the diversity in distribution systems and the threats to which they may be exposed. Instead of imposing additional prescriptive requirements for integrity management, PHMSA concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective.

Last Revision: 8/2/10

B.1.2 Why don't distribution integrity management requirements focus on high consequence areas?

The integrity management requirements for transmission pipelines are focused on portions of the pipeline where significant consequences could result if an incident occurs — so-called "high consequence areas". Transmission pipelines often traverse rural areas. This approach requires safety-improvement efforts to be focused on areas where consequences of an event would be more significant, in areas with greater human density, or more sensitive environment. Distribution pipelines are largely in developed, more populated areas, since they exist to deliver gas to those populations. As the population is in close proximity to much of these distribution systems, the consequences of an incident are similar throughout. For distribution pipelines, PHMSA concluded it is more appropriate that operators consider their entire pipelines under their integrity management programs.

Last Revision: 8/2/10

B.1.3 Why aren't distribution pipeline operators required to physically inspect their pipelines as are operators of other types of pipelines?

The assessment techniques used on hazardous liquid and gas transmission pipelines (e.g., in-line inspection, pressure testing, direct assessment) are not transferable to distribution pipe. Additionally, distribution pipelines are not subject to the same pressures as transmission pipelines and thus tend to leak rather than rupture. It is important that distribution integrity management programs be focused on identifying the conditions that can cause leaks and addressing them before the failures occur and on managing leaks effectively when and if they do occur.

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B.1.4 Have State Agencies and PHMSA communicated with operators about Distribution Integrity? What has been discussed?

States periodically host PHMSA Training and Qualifications (TQ) pipeline safety seminars for operators including those of municipal, master meters, and small LPG systems. The seminars included updates regarding proposed rules and recent final rulemakings. Communications about DIMP covered information such as the anticipated final rule date, GPTC guidance development, the purpose of the regulation, and the proposed requirements for the rule. PHMSA's Regional offices also hold safety seminars which cover new and proposed rules, current initiatives, and advisory bulletins. PHMSA and some States have and continue to speak at national and statewide operator association meetings as well as both statewide and local emergency assistance meetings.

In 2007, prior to the DIMP Notice of Proposed Rulemaking PHMSA and the States, through NAPSR, created the DIMP State-Federal Team. PHMSA and the States have been working together to advance a consistent understanding of the DIMP. We have worked jointly to identify frequently asked questions, write responses and to develop inspection forms and guidance. Our joint efforts promote more uniform and knowledgeable inspections. Additionally, PHMSA's TQ organization is working to prepare and provide timely training to state and federal pipeline safety inspectors. The group continues to meet and work together through the implementation phase.

Last Revision: 8/2/10

B.2 State and Federal Enforcement

B.2.1 How does PHMSA foresee this rule being enforced for compliance?

Inspectors will review the IM plan for quality and completeness and ensure that operators are doing what their plan says; and then inspect to see if their plan is effective. The procedures and records will be reviewed to verify that the operator performed them as written and in compliance with required dates. Enforcement will be consistent with current practice by the jurisdictional agencies.

Last Revision: 8/2/10

B.2.2 Will operators be compared against other operators or national leak or safety data?

PHMSA recognizes that operators need to develop a DIMP plan appropriate for the applicable threats, the operating characteristics of their specific distribution delivery system, and the customers that they serve. PHMSA and State partners intend to focus on each individual operator's performance trends.

Last Revision: 8/2/10

B.3 GPTC Guidance

B.3.1 Must an operator follow the Gas Piping Technology Committee (GPTC) DIMP guidelines?

No. The GPTC DIMP guidelines provide options which operators can use in implementing the high-level requirements of the rule. The GPTC DIMP guidelines are not incorporated into the rule, and thus are not regulatory requirements. Operators may use other approaches to meet the high-level requirements of the regulation as well, but in doing so they should be prepared to demonstrate to their regulators that their actions meet the rule requirements. PHMSA, State pipeline safety regulators and industry all participated in the development of the GPTC guidelines and have confidence that operators who use them in their programs will comply with the requirements of the rule.

Last Revision: 8/2/10

B.3.2 How will the GPTC guidance be used by regulators?

The GPTC Guide provides operators with valuable, consensus written guidance that can assist them in preparing their DIMP plan. The GPTC Guide is not regulation. An operator needs to follow the procedures they include in their plan. If their plan references the GPTC guidance, the regulator may verify that the operator has implemented the referenced guidance as written. However, as referenced in B.3.1 above, an operator may choose to use practices other than those in the Guide to meet compliance. The inspection is based on the regulation, not on GPTC guidance.

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B.4 SHRIMP

B.4.1 What is SHRIMP?

SHRIMP (Simple, Handy, Risk-based Integrity Management Plan) is a software application designed to assist operators in developing plans to manage the integrity of their distribution piping. It is geared toward the needs of small utilities that lack in-house engineering and/or risk management expertise. The American Public Gas Association (APGA) Security and Integrity Foundation (SIF) received funding from PHMSA for development. Contact APGA www.apga.org or the SIF www.apgasif.org for information or questions pertaining to SHRIMP.

Last Revision: 8/2/10

C. Subpart P – Gas Distribution Pipeline Integrity Management

C.1 §192.1001 What definitions apply to this subpart?

C.1.1 What was used as a basis for defining "hazardous leaks"?

The definition for hazardous leaks was drawn from the Gas Pipeline Technology Committee's (GPTC), *Guide for Gas Transmission and Distribution Piping Systems* (The Guide) in Appendix G-192-11, Section 5.5 Leak grades. GPTC ANSI Z380 is an accredited American National Standards Institute (ANSI) standards committee that develops and publishes *The Guide* to assist natural gas pipeline operators in complying with Part 192. PHMSA's Office of Pipeline Safety (OPS) is represented on this committee. Many operators now use the guidelines to classify leaks.

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C.1.2 How was the definition "excavation damage" developed?

PHMSA's definition for excavation damage closely matches the definition used in the Common Ground Alliance's (CGA) Damage Information Reporting Tool (DIRT). CGA is a national group involving operators of all types of underground facilities, as well as representatives of excavators and others who play an important part in preventing damage to underground facilities. PHMSA has omitted the phrase ''of exposure'' used in the DIRT definition, since this refers to damage from causes other than excavation (e.g., washout).

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C.2 §192.1003 What do the regulations in this subpart cover?

C.3 §192.1005 What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart?

C.3.1 If an operator has both natural gas and LPG systems, must it have two separate DIMP plans or may it have a single plan?

The operator has an option. An operator may choose to have a single DIMP plan, but it must address the requirements for both types of systems. The plan must take into account the different threats associated with the different products. Or an operator may choose to have separate DIMP plans for the natural gas and for the LPG system.

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C.3.2 Must an operator have one DIMP plan covering all of its systems or could it have separate plans for different systems or service areas?

An operator may have one master plan or separate plans, so long as its entire service area is covered. However, data from multiple plans is required to be consolidated for annual reporting purposes by state.

Last Revision: 8/2/10

C.3.3 Will companies operating in several states need to develop individual DIMP plans for each state?

The operator may have a single DIMP plan for several states; however, the operator must address any additional requirements for each state since individual states may have the authority to impose additional requirements on intrastate lines the state regulates. For example, individual States may require performance measures be provided for pipe in their state in addition to the total for the operator.

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C.3.4 What is the relationship between an operations & maintenance manual and a DIMP plan?

An O&M manual contains written procedures describing how operators conduct operations and maintenance activities on their system in accordance with Federal and State pipeline safety regulations. The activities address various threats to a pipeline's integrity. A DIMP plan is a written integrity management plan which describes the analysis of the operator's system, provides a relative risk analysis based on threats to the system, and prescribes additional or accelerated actions as needed to address risks identified in the plan.

An operator may find it convenient to incorporate additional or accelerated actions, as determined to be necessary under its DIMP plan, into its O&M manual. As the operator evaluates the effectiveness of these actions, it may identify a need to modify those actions, potentially requiring additional modifications to its O&M plan. Note that States may require a revision history, a record of modifications to the O & M manual.

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C.3.5 Is there a deadline by which operators must satisfy these requirements?

Yes, by no later than August 2, 2011, operators of gas distribution pipelines, including master meter or small LPG operators, must develop and implement an integrity management program that includes a written integrity management plan. PHMSA recognizes that implementing IM plans involves learning leading to improvement and expects that programs will evolve over time as experience is gained. However, the program developed by August 2, 2011, must address all of the required plan elements.

Last Revision: 8/2/10

C.3.7 Are operators required to include "farm taps" in their distribution integrity management plan?

In the past, distribution, gathering, and transmission operators connected landowners directly to transmission and gathering pipelines often in exchange for the right to install the pipeline across a landowner's property. This connection to the gas pipeline is commonly referred to as a "farm tap". Although new farm taps are not installed nearly as frequently as they were in the past, "farm taps" are very common. The vast majority of "farm taps" meet the definition of a distribution line given that they do not meet the criteria to be classified as a gathering line or a transmission line.

The "farm tap" is pipeline upstream of the outlet of the customer meter or connection to the customer meter, whichever is further downstream, and is responsibility of the operator. The pipeline downstream of this point is the responsibility of the customer. Some States require the operator to maintain certain portions of customer owned pipeline. The pipeline maintained by the operator must be in compliance with 49 Part 192.

Operators of distribution, gathering, and transmission lines with "farm taps" must have a distribution integrity management program meeting the requirements of Subpart P for this distribution pipeline. The DIMP plan is not required to include the customer-owned pipeline (unless required otherwise by State law). The operator having responsibility for operations and maintenance activities for the facility is responsible for developing and implementing the DIMP plan.

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C.4 §192.1007 What are the required elements of an integrity management plan?

C.4.1 What does PHMSA see as the most critical elements of the regulation?

All of the elements are critical. The plan must have written procedures for developing and implementing all the elements.

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C.4.a Knowledge

C.4.a.1 The rule requires that an operator know its system. Must an operator excavate simply to gather information about parts of its system where it may not now have complete knowledge?

No. Operators need to gather the information that they have reasonably available to develop an understanding of their pipeline systems. The data may currently reside in different locations or be the responsibility of different groups within the company. Part of this development includes identifying information that is not now known, but which is needed to develop an understanding of the characteristics of the pipeline and necessary to assess applicable threats and to analyze its risk.

Last Revision: 8/2/10

C.4.a.2 There are some characteristics about an operator's system that may not be known during the development of the IM plan. What are PHMSA's expectations for filling those voids?

Operators need to use opportunities that arise, such as the pipeline being excavated for operation, maintenance, or other reasons, to collect additional information needed to better understand their pipeline system. Operators are required to incorporate into their plan and implement procedures to gather this information when the opportunity exists. This information may or may not prompt a reevaluation of the plan, but at a minimum, will be considered for analysis during the next scheduled evaluation. Records need to be maintained and updated to reflect changes to the system. Over time, PHMSA expects that an operator's understanding of its pipeline system and the quality of their risk analyses will improve.

If an operator's records have been destroyed or are no longer available, the operator must collect sufficient information, perform appropriate tests, and create records or maps for the safer operation, maintenance, and emergency response of the system.

Last Revision: 8/2/10

C.4.a.3 Who qualifies as a "subject matter expert"?

Subject matter experts are simply people who have specific knowledge of topics and/or facilities under consideration. This includes the operator's operations and maintenance personnel – the people who construct, inspect, maintain and oversee its distribution facilities day-to-day. For some operators, this may include contractor personnel that have performed construction or operation and maintenance activities for a long period of time or for unique and/or special circumstances. In some instances, an operator may want to involve subject matter experts beyond its employees. For example, if analysis shows that an operator is having difficulty minimizing the detrimental effects of stray currents, the operator may want to involve in its program an outside person with expertise or specialized knowledge in this area.

C.4.a.4 What data will be required to be collected for new gas pipelines going in the ground?

The DIMP regulation prescribes two minimum data elements that must be captured and retained on any new distribution pipelines: the location where the new pipeline is installed and the material of which it is constructed. Pipeline, defined in §192.3, means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Additionally, operators must collect data about new gas pipelines which will be needed to assess current and future threats and risks to the pipeline's integrity. This includes information about the characteristics of the pipeline's design, operations, and the environmental factors where the pipeline is installed.

In addition, an operator must also consider the data it needs to comply with the various record keeping requirements in Part 192 such as those for pipeline design, testing, construction, corrosion control, customer notification, uprating, surveying, patrolling, monitoring, inspection, operation, maintenance, emergencies, and operator qualification. The GPTC Guide, Appendix G-192-17, provides operators with guidance on explicit requirements for reports, inspections, tests, written procedures, records and similar actions. States may have additional requirements.

Last Revision: 8/2/10

C.4.b Identify Threats

C.4.b.1 Must an operator use a computer-based risk analysis model?

No. Risk analysis is a process of understanding what factors affect the risk posed by a pipeline system and which are most important. For a complex system, use of a computer-based risk model may make this process easier, but the use of a computer based modeling system is not required. For a simple distribution pipeline system, it is possible to do a credible analysis that leads to an understanding of factors/areas that are important to risk without use of such a model. The GPTC guidelines include suggestions for simpler approaches.

Last Revision: 8/2/10

C.4.b.2 Must each of the 8 threats be considered for every pipeline type?

Yes, an operator's DIMP plan must consider each of the 8 threats for the pipeline system, but some threats may not be relevant to all pipe types or all operators' circumstances. Some threats may apply but are not obvious. For example, corrosion is not a threat to plastic facilities but could be a threat to tracer wires, transition fittings, or to short pieces of metal main or services in a plastic system. Material or weld failures could apply to plastic (the brittle failure issue and potential for faulty fusion joints, for instance). Excavation damage occurs regardless of the pipe material.

Last Revision: 8/2/10

C.4.c Evaluate and Rank Risks

C.4.c.1 What are the key things an operator should be focusing on when developing an effective risk assessment methodology?

High-quality data is core to an effective risk assessment. The integrity management plan must contain procedures for how the operator evaluates and ranks risks. Operators need to have a plan to identify and define the data necessary for the analyses. Additionally, processes should be in place to provide for data accuracy, completeness, and consistency. They should have a procedure to validate data and improve future data collected.

Operators must consider the risks (likelihood as well as the consequences of a failure) that might result from each threat. A potential incident of relatively low likelihood which produces significant consequences may be a higher risk than an incident with somewhat greater likelihood which may not produce major consequences.

Last Revision: 8/2/10

C.4.c.2 From which date are operators required to collect data for their plan?

Operators should use the information they already have and start keeping additional data to develop their plan (e.g., assess the threats) as soon as possible. They need to assemble and evaluate enough data to be able to evaluate the risk. Useful and usable historical data is needed to identify threats and trends.

Last Revision: 8/2/10

C.4.d Identify and Implement Measures to Address Risks

C.4.d.1 Must an operator implement additional or accelerated actions to reduce risk from its pipeline?

The DIMP rule is intended to improve safety performance. Improving performance may require operators to implement additional or accelerated actions to manage identified system risks, but in other instances such actions may not be required. Some operators have already implemented additional risk control and mitigation activities voluntarily. It is possible that these ongoing actions already adequately address the risks that are significant to some pipeline systems.

What the DIMP Rule does require is for operators to periodically consider potential improvements to their IM program. Operators must perform a risk analysis to understand the factors that are important to their risk and should compare the results of this analysis to the actions now being taken to assure pipeline safety. If gaps are identified (i.e., instances in which some factor important to risk is not now being adequately addressed) then appropriate risk control practices may need to be implemented. Operators also may find it appropriate to reduce some non-mandated actions now being taken (e.g., which address risks of lower importance) and to reallocate those resources to address higher priority risks. Operators must still comply with all the requirements of the regulations.

Last Revision: 8/2/10

C.4.d.2 How will small operators, with limited staff, be able to implement the requirements for risk analysis and selection of risk control measures?

The level of analysis required and risk control measures to be implemented are related to the complexity of an operator's distribution pipeline system and the variability of threats across a system. Operators with small staffs typically operate smaller, simpler systems, so that the effort required to conduct risk analysis and to select risk control measures should be less than that required of operators of more-complex systems.

PHMSA published, "*Guidance on Carrying Out Requirements in the Gas Distribution Integrity Management Rule Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines,*" to help large and small, master meter, and LPG operators implement the requirements of subpart P of Part 192. Guidance for large and small operators begins at section I and for master meter and LPG operators at section V of this document. The document is located on the PHMSA's DIMP web site under DIMP Key Documents http://primis.phmsa.dot.gov/dimp/documents.htm.

The Gas Piping Technology Committee (GPTC) DIMP guidelines provide guidance on relatively-simple approaches to risk analysis. The American Public Gas Association (APGA) Security and Integrity Foundation, with partial funding from PHMSA, developed the Simple, Handy, Risk-Based, Integrity Management Plan (SHRIMP), a computer-based program that is intended to assist small operators in preparing a plan to meet rule requirements.

Last Revision: 8/2/10

C.4.d.3 If an operator already has a leak management program, does the operator have to implement a new program in response to this regulation?

Not necessarily. Operators may not need to implement new leak management programs. Rather, operators should review their current leak management program to assure that it is effective and when needed, adjust their program to comply with the regulation. Leak management is an important factor in managing the risks associated with distribution pipeline systems. PHMSA recognizes that distribution pipeline operators currently have leak management programs in place and that these programs are generally effective. For example, corrosion is a leading cause of distribution pipeline leaks, but corrosion is only the cause of four percent of reportable distribution incidents; PHMSA believes that effective leak management is a major reason for this performance – operators identify and address severe leaks before incidents occur.

Last Revision: 8/2/10

C.4.d.4 Why not simply require operators of gas distribution pipelines to replace old pipe?

The rule requires that operators analyze their pipeline systems to identify the hazards that affect them and evaluate the risks posed by each threat. Operators must determine and implement measures designed to reduce the risks from failure. Pipe replacement is certainly one action an operator could take to mitigate some risks to its system.

Simply because a pipeline is old, does not mean that it is a risk to public safety. Some types of older pipe operate safely and have not been involved in incidents. Meanwhile, some newer pipes, including particular kinds of plastic fittings, have proven problematic and have caused incidents. State regulators have occasionally required operators to implement pipe replacement programs, but these replacement programs have been targeted to specific problematic pipe based on the local circumstances facing particular operators. Operators already are required to initiate programs to recondition or phase out segments of pipelines determined to be in unsatisfactory condition. Threats such as excavation damage, which is the leading cause of distribution pipeline incidents, would not be addressed by a pipe replacement program. The rule requires gas operators to analyze the risk of their pipeline, given their unique circumstances, including the age of their pipeline system. Operators should use these risk analyses to identify actions to reduce risk, including the possibility of replacing selected pipe. Regulators may oversee an operator's risk management decisions.

Last Revision: 8/2/10

C.4.d.5 What kind of issues should an operator focus on in addressing the threat of Excavation Damage as part of its DIMP Plan?

Excavation damage is the leading cause of "significant" pipeline incidents (causing injury or fatality). PHMSA published a document entitled, *Damage Prevention Assistance Program (DPAP): Strengthening State Damage Prevention Programs*. Building on the nine elements of effective damage prevention programs found in the *Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES)*, this document provides guidance to stakeholders for strengthening state damage prevention programs. While not all of these nine elements are within the operator's direct control, certain operators working with state regulators and other stakeholder groups have found ways to facilitate progress in addressing the nine elements.

Last Revision: 8/2/10

C.4.d. 6 In order to eliminate the need for a leak management program, how quickly would an operator need to repair all leaks?

The rule states that a leak management program is not needed if all leaks are repaired when found. All hazardous leaks must be repaired promptly. To eliminate the need for a leak management program, an operator would need to continue to work on each leak, hazardous and non hazardous, until it is eliminated as opposed to scheduling the repair or periodically monitoring the leak.

Last Revision: 8/2/10

C.4.d.7 Can the installation of excess flow valves be a method to mitigate risks?

Excess flow valves are one means to reduce the consequences of a potential incident when properly designed and installed. The valve automatically shuts off the flow of gas in a service line when the gas flow in the line exceeds the valve setting. The valve trips when there is severe damage to the pipeline, significantly increasing the gas flow rate. Such significant increases in gas flow rate are most often caused by excavation damage that ruptures the service line downstream of the valve. The risk of the excavation damage still exists. EFVs are an efficient means of reducing the consequences in densely populated areas, on services to public or difficult to evacuate buildings, or areas where operators cannot reach rapidly shut off the flow of gas in an emergency. The GPTC DIMP Guidance identifies the use of an EFV as a possible risk mitigation measure.

C.4.e Measure Performance, Monitor Results, and Evaluate Effectiveness

C.4.e.1 Why has PHMSA selected the performance measures that it has for periodic reporting?

Measuring performance periodically allows operators to determine whether actions being taken to address threats are effective, or whether different actions are needed. It is also important for PHMSA and the States to measure the safety improvement (i.e., performance) achieved by this new regulation. Ultimately, a decrease in the number and consequences of distribution pipeline incidents will be the true measure of success, but it will take many years of accumulating data to determine with confidence that there is a declining trend in incidents/consequences. PHMSA needs data that will be useful in a shorter time frame to show whether improvements are being realized or if further adjustments to requirements are needed.

PHMSA has concluded it would be most useful for operators to report four performance measures. PHMSA recognizes that there will be some variability in the criteria for these performance measures among operators. The performance measures are intended to measure individual operator, state, and national trends.

The total number of leaks eliminated or repaired by cause and the number of hazardous leaks eliminated or repaired by cause are two of the reportable performance measures. Leaks can lead to incidents and hazardous leaks represent the highest risk leaks. PHMSA and State partners expect effective integrity management programs to produce a reduction in the number of leaks. The total number of leaks scheduled for repair has historically been part of the Annual Report submitted by operators of distribution pipelines.

The other reportable performance measures are the number of excavation damages and the number of excavation tickets. Excavation damage is the leading cause of significant distribution pipeline incidents. The number of excavation tickets is an indicator of the total amount of excavation activity in an area. This data will be used to normalize the reported number of excavation damages in analyzing performance since excavation damages occur as an unintended consequence of digging. PHMSA and State partners would expect effective integrity management programs to produce a positive trend in the level of excavation damage per the number of damages per ticket (or per 1000 tickets) over time.

Last Revision: 8/2/10

C.4.f Periodically Evaluation and Improvement

C.4.f.1 How often does an operator need to evaluate its program?

Operators must evaluate their program at a period appropriate for their system, but at an interval not exceeding five years. An operator should re-evaluate its IM program whenever new knowledge, new threats or other information would substantially alter the operator's DIMP program. This could range from once each calendar year to less frequently, but must not exceed once every five years.

Last Revision: 8/2/10

C.4.g Report Results

Performance Measures

C.4.g.1 When must operators start collecting and maintaining records with data needed for performance measures?

Reportable performance measures are to be submitted via the Gas Distribution Annual Report for Calendar Year 2010 which covers activities from January 1, 2010 thru December 31, 2010. The 2010 calendar year Annual Report is due by March 15, 2011.

(Note: The due date for reporting performance measures is currently under review).

Last Revision: 8/2/10

C.4.g.2 When are performance measures due on Annual Reports?

The reportable performance measures are to be submitted via the 2010 Gas Distribution Annual Report form which is due by March 15, 2011. An operator also must report this information to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

Mar. 15, 2011 – Operators use proposed revised Gas Distribution Annual Report form, PHMSA F 7100.1-1 (12-05). It contains fields for reportable performance measures for the 2010 calendar year. Mechanical fitting failures are not to be reported for calendar year 2010. A copy of the FR Notice and the Forms may be found on-line in the Docket under OMB Control Number "2137–0522" or at the following URL:

http://phmsa.dot.gov/pipeline/regs/rulemaking

Mar. 15, 2012 - Annual Report for calendar year 2011 must contain the required data for reportable performance measures from January 1, 2011 thru December 31, 2011 and information pertaining to mechanical fitting failures.

(Note: The due date for reporting performance measures is currently under review.)

Last Revision: 8/2/10

C.4.g.3 Can PHMSA further define the number of excavation tickets on the new form?

The definition of an "excavation ticket" varies among state one-call programs. Requiring operators to track tickets in two ways— one matching their one-call program definition and one matching a common national definition, would entail considerable additional effort without commensurate benefit. PHMSA encourages operators to use the criteria currently in place with the State law and one-call center which determines when notifications should be made.

The total number of excavation tickets includes all receipts of information by the underground facility operator from the notification center. Operators may choose to include or not include receipts of information directly from excavators or others. An operator's reporting criteria should remain consistent from year to year.

Last Revision: 8/2/10

C.4.g.4 For municipal operators or joint utility operators, should the number of excavation tickets include all excavation tickets or just those sent to the gas department?

The number of excavation tickets should only include a count of the receipts of information from the notification center to the gas pipeline underground facility operator.

Last Revision: 8/2/10

C.4.g.5 Are multiple tickets for a single job counted as a single excavation ticket?

Some state laws require excavators to call in additional requests for on-going jobs prior to the life of the first excavation request expiring. In reporting data these additional requests for excavation projects of extended duration may be counted since there is excavation work associated with those requests. However, operators do not need to change the criteria for counting excavation tickets for the purpose of reporting performance measures. If they currently count multiple tickets for a single job, they may continue that practice. The definition of "ticket" should remain consistent with State law and one-call center definition.

Last Revision: 8/2/10

C.4.g.6 What if the excavation damage occurs on an excavation with no ticket?

The occurrence must be reported in the number of excavation damages but not counted as an excavation ticket. The lack of a ticket likely means that damage prevention activities associated with one-call programs did not occur and that damage may thus have been more likely.

Last Revision: 8/2/10

C.5 §192.1009 What must an operator report when a mechanical fitting fails?

C.5.1 Why is PHMSA collecting data about mechanical fitting failures?

PHMSA has seen some regional issues with mechanical fittings. PHMSA plans to analyze the national data from the Annual Reports to develop better information about the types and causes of fitting failures. This information will be communicated to operators so that they can act appropriately.

Last Revision: 8/2/10

C.5.2 Do States already collect the type of information that is to be collected for mechanical fitting failures?

Not fully. Mechanical fitting failure information has been collected in Annual Reports and Incident Reports as a subset of the "material and weld", "equipment", and "other" failure sections. The information collected on the reportable incident form was limited to the type of joint and the cause of the failure, either construction or material defect and was only reported if the mechanical fitting failure resulted in a reportable incident. On the Annual Report, the mechanical fitting failures would be included in the count of "Leaks Eliminated/Repaired During Year", categorized by threat. The information now being collected for mechanical fitting failures is more detailed but excludes instances that result in non-hazardous leaks. The incident report was updated on January 31, 2010. For a copy of the report, go to PHMSA's web site at http://www.phmsa.dot.gov/pipeline/library/forms .

Last Revision: 8/2/10

C.5.3 Should both steel and plastic mechanical fitting failures be reported? How about the different styles of plastic mechanical fittings?

All types of mechanical fitting failures should be included regardless of material. The objective of the data collection is to identify mechanical fittings which, based on a historical data, are susceptible to failure. The Advisory Bulletin ADB-86-02 and the update to it, ADB-08-02, identified issues with mechanical fittings which could lead to failure. The bulletin advised operators to perform certain actions. Determining the root cause of these mechanical fitting failures is important to determine if and what type of additional actions may be needed if trends are identified. PHMSA intends for operators to report all types and all sizes of mechanical fitting failures which result in a hazardous leak. The failure can occur on a fitting connected to a pipe or a fitting that joins sections of pipe. Mechanical fittings include stab, nut follower, and bolt type fittings. The reporting requirements apply to failures in the bodies of mechanical fitting or failures in the joints between the fittings and pipe.

Operators are to report mechanical fitting failures as the result of any cause including excavation damage. Mechanical fittings are to be included regardless of the material they join. Include mechanical fittings which join steel to steel, steel to plastic, and plastic to plastic. Examples of the use of mechanical fittings may be found in the following applications: service tees, tapping tees, transition fittings, couplings, risers, sleeves, ells, "Ys", and tees. Failures on fittings that are joined by solvent cement, adhesive, heat fusion, or welding are not to be reported as mechanical fitting failures.

Last Revision: 8/2/10

C.5.4 Since there is a new section for mechanical fitting failures, do these failures still need to be reported under Part C of the Annual Report?

Yes, in addition to the new reporting requirements for hazardous mechanical fitting failures in section, "Part F – Mechanical Fitting Failure Data", both the number of total leaks and the number of hazardous leaks eliminated or repaired during the year due to mechanical fittings are still reported in "Part C – Total Leaks and Hazardous Leaks Eliminated/Repaired During Year".

Last Revision: 8/2/10

C.5.5 Must operators report to PHMSA mechanical fitting failures that occurred historically (i.e., before a final DIMP rule became effective)?

Currently the DIMP rule states that operators need to collect data about mechanical fitting failures that result in hazardous leaks starting January 1, 2010 but PHMSA published a Federal Register notice on June 28, 2010 to inform operators that the portion of the Annual Report relative to mechanical fitting failures will be delayed by one year and will take effect starting with the 2011 calendar year. PHMSA is developing a final rule to revise the dates in the regulation.

Last Revision: 8/2/10

C.6 §192.1011 What records must an operator keep?

C.7 §192.1013 When may an operator deviate from required periodic inspections of this part?

C.7.1 How can operators use their DIMP programs to justify reductions in other periodic test and inspection requirements?

Part 192 includes requirements to perform certain tests and inspections periodically. For example, leak surveys must be conducted annually in business districts and atmospheric corrosion surveys must be conducted every three years on exposed pipe. These activities are intended to address a potential threat to distribution pipeline integrity. As operators complete risk analyses and implement measures directed at addressing threats of particular importance to their pipeline systems, the relative value of these required periodic activities could be shown to decrease in specific areas.

The rule includes a provision which allows operators to submit proposed adjustments to the frequency of periodic actions now required in Part 192, based on the results of their risk assessment in their integrity management programs and engineering analysis. Proposed changes will be reviewed by the regulatory authority exercising oversight of the operator and can be approved if the authority agrees that the proposed changes provide an equal or improved overall level of safety. This provision is intended to allow operators to shift resources from generically-required periodic risk control activities to activities that are more specifically focused on the issues of importance to their particular pipeline systems. The proposal must provide an equal or greater overall level of safety.

Last Revision: 8/2/10

C.7.2 What will PHMSA (or States) require for proposals for alternate inspection intervals?

Proposals must be submitted to each applicable oversight agency (usually the State). Each State will implement this provision under the State's procedures. State authorities and regulatory structures differ. Requirements for consideration of an alternative interval may differ among State regulatory authorities. The regulatory authority will be responsible for reviewing each proposal, determining safe intervals based on the information in the operator's proposal, and approving or rejecting the proposal.

Proposed alternative inspection intervals must demonstrate an equal or improved overall level of safety including the effect of the reduced frequency of periodic inspections. A quantitative estimate of risk is not required. PHMSA is developing criteria for evaluating an operator's alternative interval proposal in the states where PHMSA exercises enforcement authority over distribution pipelines.

Last Revision: 8/2/10

C.8 §192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart? *(Answers from §192.1007 apply to this section unless otherwise noted).*

General

C.8.1Are all LPG operators and natural gas operators, regardless of the size of their distribution system, subject to the DIMP regulation?

The distribution integrity management regulation applies LPG and natural gas operators of all sizes except as provided in 192.1(b).

The requirements under DIMP are the same for master meter operators and small LPG operators. Section 192.1015 is specific to these operators. A master meter operator means a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as by rents. LPG operators serving fewer than 100 customers from a single source are considered small LPG operators. PHMSA used the criterion from section 191.11 which excludes LPG operators serving fewer than 100 customers from a single source from the requirement to file an Annual Report.

LPG operators serving100 or more customers from a single source must meet the same requirements applicable to all natural gas operators. Section 192.1007 is specific to these operators.

Last Revision: 8/2/10

C.8.2 Why are master meter and small LPG operators subject to different requirements?

The requirements for these smaller operators recognize the less complicated nature of their facilities. Master meter and small LPG systems are generally small and cover limited geographic areas. These operators often have more direct control over excavation in the area in which they operate, providing more positive control over what is the greatest risk to a distribution pipeline system. The systems are also less diverse, usually involving only pipe, meters, and service regulators. There have been few significant incidents on master meter and LPG distribution systems. This justifies a reduced set of integrity management requirements.

Last Revision: 8/2/10

Elements

C.8.a Knowledge

C.8.b Identify Threats

C.8.c Rank Risks

C.8.d Identify and Implement Measures to Mitigate Risks

C.8.e Measure Performance, Monitor Results, and Evaluate Effectiveness

C.8.f Periodically Evaluation and Improvement